COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF

VIRGINIA ELECTRIC AND POWER COMPANY **CASE NO. PUR-2021-00045**

For approval of a rate adjustment clause, designated Rider CCR, for the recovery of costs incurred to comply with § 10.1-1402.03 of the Code of Virginia, pursuant to Virginia Code § 56-585.1 A 5 e

REPORT OF MARY BETH ADAMS, HEARING EXAMINER

September 3, 2021

In its Petition, the Company seeks recovery of costs associated with CCR Projects located at its Bremo, Chesterfield, Possum Point, and Chesapeake Energy Center Power Stations. No participant challenged the reasonableness of the costs proposed to be recovered through Rider CCR. Based on the evidence and the Code, I recommend the Commission approve the $216.146 million revenue requirement for Rider CCR and that costs be recovered based on the Factor 3 allocation methodology proposed by the Company and supported by Consumer Counsel and Staff. In addition, I recommend the Company be required to perform the Class 2 Study for the Bremo and Possum Point Power Stations.

HISTORY OF THE CASE

On February 26, 2021, pursuant to § 56-585.1 A 5 of the Code of Virginia ("Code") and the State Corporation Commission's ("Commission") Rules Governing Rate Applications and Annual Informational Filings of Investor-Owned Electric Utilities,[1] Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("Dominion Energy" or "Company") filed with the Commission its petition requesting approval of a rate adjustment clause ("RAC"), designated Rider Coal Combustion Residuals ("Rider CCR"), for recovery of costs incurred to comply with Virginia Senate Bill 1355 ("SB 1355"),[2] codified as Code § 10.1-1402.03 ("Petition"). Concurrent with the Petition, the Company filed a Motion for Entry of a Protective Order and Additional Protective Treatment.

On March 18, 2021, the Commission issued an Order for Notice and Hearing, which, among other things, assigned this case to a Hearing Examiner to conduct all further proceedings in this matter on behalf of the Commission, including filing a final report containing the Hearing Examiner's findings and recommendations.

On March 24, 2021, a Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information was issued establishing procedures for the filing, exchange

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[1] 20 VAC 5-204-5 *et seq.* ("Rate Case Rules").

[2] 2019 Va. Acts ch. 651.

and handling of confidential and extraordinarily sensitive information and documents in this case.

Timely notices of participation were filed by the Virginia Committee for Fair Utility Rates ("Committee") and the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel").

On May 4, 2021, the Company filed its proof of notice and service.[3]

On June 10, 2021, the Company filed a Motion for Leave to File Supplemental Direct Testimony. On June 14, 2021, a Ruling was issued granting the Company's Motion for Leave to File Supplemental Testimony and accepting for filing the supplemental testimonies of Jared R. Robertson and Paul B. Haynes.

On June 14, 2021, a Ruling was issued directing that the July 27, 2021 hearing be held virtually and establishing certain procedures for the virtual hearing.

On June 17, 2021, the Committee filed the testimony of Stephen J. Baron. Consumer Counsel did not file testimony.

On June 22, 2021, Commission Staff ("Staff") filed its testimony in this proceeding, and on July 7, 2021, the Company filed its rebuttal testimony.

The July 27, 2021 hearing convened as scheduled. Lauren Wood Biskie, Esquire, Elaine S. Ryan, Esquire, and Timothy D. Patterson, Esquire, appeared on behalf of the Company. Edward L. Petrini, Esquire, and Timothy G. McCormick, Esquire, appeared on behalf of the Committee. C. Meade Browder, Jr., Esquire, and John E. Farmer, Jr., Esquire, appeared on behalf of Consumer Counsel. Kiva Bland Pierce, Esquire, and Andrea B. Macgill, Esquire, appeared on behalf of Staff.

No public witnesses testified at the hearing and no written comments were filed on the Petition.

On August 2, 2021, the Committee filed an Unopposed Motion to Adjust Due Date for Filing Post-Hearing Briefs ("Motion") requesting that the due date for filing post-hearing briefs be extended from August 13, 2021 to August 16, 2021. A Ruling granting the Motion was issued on August 3, 2021.

SUMMARY OF THE RECORD

DOMINION ENERGY'S DIRECT TESTIMONY

The Company submitted the testimonies and exhibits of the following: Brandon E. Stites, Vice President, Project Construction; Lisa C. Messinger, Director, Environmental Services;

[3] Ex. 1.

Jared R. Robertson, Regulatory Analyst, Regulatory Accounting; and Paul B. Haynes, Director, Regulation.

Mr. Stites provided an overview of the Petition. He stated that the Company is seeking to recover actual and projected cash expenditures for certain environmental projects ("CCR Projects" or "Projects") involving CCR, or coal ash, at the Company's Bremo Power Station, Chesterfield Power Station, Possum Point Power Station, and Chesapeake Energy Center ("Power Stations").[4] He discussed the construction plans, schedule, and costs for the CCR Projects. He testified that the total estimated cost of the CCR Projects is $2.716 billion, excluding financing costs.[5] Mr. Stites sponsored Filing Schedule 46A, which provides additional cost details.

He provided an overview of SB 1355, which requires the Company remove all CCR from certain storage units at each power station in accordance with applicable standards and either (a) beneficially reuse it in a recycling process for encapsulated beneficial use; or (b) dispose of the CCR in a permitted landfill in a facility and in a manner prescribed by law.[6] SB 1355 also mandates the Company beneficiate at least 6.8 million cubic yards of CCR from at least two Power Stations, development of a transportation plan regarding CCR removal, identification of options for utilizing and prioritizing hiring of local workers, and compliance with various reporting requirements.[7]

According to Mr. Stites, the Company plans to meet the requirements of SB 1355 through the following Projects to be undertaken at each Power Station:

- Bremo: Construct a new landfill on adjacent property to receive approximately 6 million cubic yards of CCR from the North Ash Pond, which will subsequently be closed.[8] The Company is evaluating alternative approaches in the event the construction of a landfill onsite is not possible.[9] The total estimated cost of the Bremo Project is approximately $529.9 million.[10] Through December 2020, The Company has spent $12.6 million on the Bremo Power Station CCR Project.[11]

- Chesterfield: Recycle up to 7.5 million cubic yards of CCR and transfer the remaining approximately 7.5 million cubic yards of CCR to an existing management facility on Company-owned, non-contiguous property.[12] The Company has signed a Memorandum of Understanding with Chesterfield County regarding a transportation plan to move the

[4] Exs. 3 and 3ES, at 2.
[5] *Id.*
[6] *Id.* at 5.
[7] *Id.* at 5-6.
[8] *Id.* at 7.
[9] *Id.*
[10] *Id.* at 8.
[11] *Id.*
[12] *Id.* at 9.

CCR materials.[13] Mr. Stites described the access improvements that Chesterfield County will make to nearby Henricus Historical Park as a result of the agreement with the Company.[14] He stated that the costs associated with the Chesterfield County agreement are included in the "Other Construction" line of the Upper Ash Pond and Lower Ash Pond Cost Reports provided in his Schedule 2 and Filing Schedule 46A and reported that the estimated cost for the Rate Year is approximately $19 million.[15] The total estimated cost of the Chesterfield Project is $1.613 billion.[16] Mr. Stites described the work that has been done to date and stated that, through December 2020, the Company has spent $32.7 million, which primarily represents costs for engineering, pre-construction, and water treatment activities.[17] Additionally, he described the excavation work that will need to be done in connection with the Chesterfield Power Station.[18]

- Possum Point: Construct a new onsite landfill to move approximately 4 million cubic yards of CCR.[19] Other alternative options are also being considered.[20] The total estimated cost of the Possum Point Project is $347.1 million.[21] Mr. Stites reported that through December 2020, the Company has spent $3.7 million on the Possum Point Power Station CCR Project, which represents costs associated with engineering and permitting activities.[22]

- Chesapeake Energy Center: Beneficiate as much as possible of the existing 2 million cubic yards of CCR, after which the pond/landfill would be closed.[23] He stated that the Company is currently awaiting resolution of a legal dispute with the City of Chesapeake concerning the necessity of a Conditional Use Permit before it proceeds with identifying a vendor to beneficiate the CCR removed from the site.[24] The total estimated cost of the Chesapeake Energy Center Project is $225.5 million.[25] Through December 2020, the Company has spent $2.3 million on the Chesapeake Energy Center CCR Project.[26] The costs were primarily for engineering activities.[27]

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[13] *Id.* at 10-11.
[14] *Id.* at 11-12.
[15] *Id.* at 12.
[16] *Id.* at 13.
[17] *Id.* at 13-14.
[18] *Id.* at 14.
[19] *Id.* at 15.
[20] *Id.*
[21] *Id.* at 16.
[22] *Id.*
[23] *Id.*
[24] *Id.*
[25] *Id.* at 17.
[26] *Id.*
[27] *Id.*

In conclusion, Mr. Stites asserted that he believes the expenditures for each of the CCR Projects at the Power Stations are reasonable and prudently incurred.[28] He confirmed that the Company plans to meet the SB 1355 requirement to identify options for utilizing and prioritizing the hiring of local workers and advancing the Commonwealth's workforce goals in consultation with the Commonwealth's Chief Workforce Development Officer.[29]

Ms. Messinger provided an overview of the state and federal environmental regulations that mandate the CCR Projects and result in the costs being sought for recovery in Rider CCR. Specifically, she identified the following regulations and environmental requirements applicable to the Petition: (1) the United States Environmental Protection Agency's ("EPA") "Hazardous and Solid Waste Management System; Disposal of [CCR] from Electric Utilities; Final Rule," ("CCR Rule"); (2) SB 1355, codified at § 10.1402.03 of the Code; (3) Virginia's Solid Waste Management Regulations "Standards for Disposal of [CCR] in Landfills and Surface Impoundments" ("SWMR Part 81"); and (4) EPA's "Criteria for Municipal Solid Waste Landfills" ("Part 258 Criteria").[30]

She explained that the CCR Rule requires an owner/operator of an existing CCR surface impoundment unit to close the pond for certain reasons.[31] Further, she explained that the CCR Rule provides two options for CCR pond closure: (1) closure in place, also referred to as cap-in-place; and (2) closure by removal or excavation.[32]

Next, she described SB 1355 and pointed out that it specifies exceptions to the closure options granted under the CCR Rule.[33] Specifically, it prohibits the capping and closing in place of the existing CCR ponds and instead mandates excavation and disposal of the ash into a lined, permitted landfill or by recycling.[34] The law allows for either construction of onsite landfills, which must meet the CCR Rule landfill construction standards, or landfilling offsite at a landfill that meets or exceeds Part 258 Criteria.[35] Pursuant to that legislation, if economically feasible to do so, the Company must also recycle or beneficiate approximately 25% of the excavated coal ash.[36] It further mandates the completion of closure of the CCR unit no later than 15 years after initiating the closure process.[37]

Ms. Messinger also discussed SWMR Part 81, which establishes a permitting program for CCR landfills and surface impoundments, and the Company's compliance with these permitting requirements.[38] She explained that there are multiple commercial landfills in Virginia similar to

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[28] *Id.*
[29] *Id.*
[30] Ex. 12, at 2.
[31] *Id.* at 3.
[32] *Id.*
[33] *Id.* at 4.
[34] *Id.*
[35] *Id.*
[36] *Id.*
[37] *Id.*
[38] *Id.*

the landfills proposed in this case that have been determined to meet Part 258 Criteria and are available to the Company.[39]

Mr. Robertson provided the calculation of the revenue requirement associated with the Rider CCR Projects, as well as supporting financial information and accounting procedures and controls.

He confirmed that the Company is proposing a 9.2% return on common equity ("ROE"), as approved by the Commission in its Final Order in the Company's 2019 ROE Proceeding, Case No. PUR-2019-00050.[40] He identified the rate year as December 1, 2021 through November 30, 2022 ("Rate Year").[41]

He explained that the two key components of the revenue requirement for the Rider CCR Projects are the Projected Cost Recovery Factor and the Actual Cost True-Up Factor.[42] In calculating the Projected Cost Recovery Factor, the Company is proposing to amortize projected balances of the deferred pre-RAC costs and the associated financing costs, and the projected monthly cash expenditures attributable to the CCR Projects.[43] He explained that the Actual Cost True-Up Factor will credit to, or recover from, customers any over-/under-recovery of costs from the most recently completed calendar year.[44] He pointed out that, since the Petition represents the initial request for cost recovery for SB 1355-mandated costs, no true-up is included in this proceeding.[45] He anticipates that any true-up for calendar year 2021 will be included in a 2022 update filing for implementation during a December 1, 2023 – November 30, 2024 rate year.[46]

Mr. Robertson stated that the Company began to incur costs related to compliance with SB 1355 in July 2019 and deferred on the Company's books costs incurred before the Rate Year, along with associated financing costs.[47] He stated that the Company is following a cash-based approach to the CCR Projects and that the amounts included in the revenue requirement for Rider CCR only represent the actual expenditures paid or the projected expenditures to be paid during the Rider's pre-RAC period and subsequent Rate Year.[48]

Mr. Robertson confirmed that no expenses requested for recovery in the Petition will be requested for recovery in any of the Company's unrelated filings, including base rates, fuel, sales and use tax, or other unrelated rider cases.[49] He stated that the Company is requesting a total

[39] *Id.* at 5.
[40] Ex. 10, at 3.
[41] *Id.*
[42] *Id.*
[43] *Id.*
[44] *Id.*
[45] *Id.*
[46] *Id.*
[47] *Id.* at 4.
[48] *Id.* at 5.
[49] *Id.* at 6.

revenue requirement of $216.146 million in Rider CCR for the Rate Year.[50] He noted that the Projected Cost Recovery Factor total accounts for the entire revenue requirement in this case.[51]

Mr. Robertson sponsored Filing Schedules 3-5 and 8, which provide information regarding the Company's cost of capital, and Filing Schedule 46B, which provides annual revenue requirement information for the proposed RAC.

Mr. Haynes sponsored the Rider CCR RAC.[52] He described the mechanism for recovery of Rider CCR costs, as set forth in § 10.1-1402.03 H of the Code, which provides that any costs associated with closure of a CCR unit "shall be allocated to all customers of the utility in the Commonwealth, irrespective of the generation supplier of any such customer."[53] He pointed out that there are no exceptions under the statute.[54] In addition, he noted that the statute provides that "any such costs that are allocated to the utility's system customers outside of the Commonwealth that are not actually recovered from such customers shall be included for cost recovery from jurisdictional customers in the Commonwealth through the [RAC]."[55]
Mr. Haynes explained how the Company proposes to allocate the projected revenue requirement to the Virginia jurisdiction.[56] Specifically, he proposed allocating the costs of CCR removal to customers based on energy usage, and proposed that such costs be recovered through a non-bypassable uniform charge per kilowatt-hour ("kWh") from all customers in the Virginia jurisdiction, irrespective of their generation supplier.[57] He stated that SB 1355 reflects a policy determination that all customers should bear the costs to remove CCR material and compared it to another recent policy determination to create the Percentage of Income Payment Plan ("PIPP"), which will utilize a uniform charge, like the Company is proposing in this case.[58] He presented the Rider CCR tariff sheet in his Schedule 3, attached to his testimony.

In addition, Mr. Haynes addressed the impact that the Rider CCR rates will have on customer bills.[59] The implementation of the proposed Rider CCR on December 1, 2021, will increase the residential customer's monthly bill, based on 1,000 kWh per month, by $2.95.[60]

Mr. Haynes reported that the Company requests, for billing purposes, a rate effective date for usage on and after December 1, 2021.[61]

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[50] *Id.* at 7.
[51] *Id.*
[52] Ex. 13, at 2.
[53] *Id.* at 3.
[54] *Id.*
[55] *Id.*
[56] *Id.* at 3-7.
[57] *Id.* at 6.
[58] *Id.* at 7.
[59] *Id.* at 7-8.
[60] *Id.* at 7.
[61] *Id.* at 2.

Mr. Haynes sponsored Filing Schedule 46C, which provides the details of the Company's methodology for allocating the Rider CCR revenue requirement and the development of a uniform charge per kWh, as well as Rider CCR's long-term annual revenue requirement by class.

DOMINION ENERGY'S SUPPLEMENTAL TESTIMONY

The Company filed the supplemental testimonies of Messrs. Robertson and Haynes.

In his supplemental testimony, **Mr. Robertson** provided a revised revenue requirement for Rider CCR based on an update to the 2019 Virginia Jurisdictional Allocation Factor.[62] Incorporating this update decreased the Company's originally filed revenue requirement amount of $216,146,000 by $60,000, for a supplemental revenue requirement amount of $216,087,000.[63]

Mr. Haynes discussed and sponsored an update to the jurisdictional allocation factor, Factor 3 CCR Non-bypassable for 2019, related to the update identified in the Company's May 18, 2021 Supplemental Triennial Review Filing in Case No. PUR-2021-00058.[64] In addition, he discussed and sponsored the Rider CCR RAC based on the updated revenue requirement presented in the supplemental direct testimony of Company witness Robertson.[65] He testified that implementation of the proposed Rider CCR on December 1, 2021, will increase the residential customer's monthly bill, based on 1,000 kWh per month, by $2.94.[66] In addition, he presented a summary of the impacts to the typical residential customer's monthly bill as of December 1, 2021, from the Company's proposed RACs.[67] He also updated Factor 3 for the Virginia jurisdiction for the period of 2001 through 2019.[68]

RESPONDENT TESTIMONY

<u>Committee</u>

The Committee filed the direct testimony of Stephen J. Baron, President and Principal of Kennedy and Associates.

Mr. Baron asserted that the Company's proposal to recover Rider CCR costs based on a uniform $/kWh charge from all rate classes and customers is unreasonable.[69] He stated that the use of non-loss adjusted, metered energy usage to allocate CCR-related fixed costs is inconsistent with cost causation and cost of service principles and sends price signals to customers that are not economically efficient.[70] He contended that landfill investment costs and

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[62] Ex. 11, at 1.
[63] *Id.* at 2.
[64] Ex. 14, at 1, Supplemental Schedule 1.
[65] *Id.* at 2, Supplemental Schedules 2 and 3.
[66] *Id.* at 2-3, Supplemental Schedule 4.
[67] *Id.* at 3, Supplemental Schedule 5.
[68] *Id.* at Supplemental Schedule 6.
[69] Ex. 20, at 5.
[70] *Id.* at 6.

other CCR-related costs do not vary with customer kWh usage, regardless of how the CCRs originally were produced.[71] According to Mr. Baron, the Company's cost allocation sends a signal to customers that reducing energy usage, even during off-peak hours, would lead to lower CCR remediation costs, when in fact, CCR costs are fixed cost and there would be no reduction in Rider CCR cost recovery if a customer curtails its off-peak energy usage.[72]

Mr. Baron described the type of costs the Company seeks to recover through Rider CCR.[73] He asserted that the costs are not being incurred to provide energy to the Company's customers but are fixed costs that are being incurred to operate the Company's system.[74] Mr. Baron pointed out that the Commission has previously found the Company's CCR-related costs should be allocated using the Average and Excess ("A&E") methodology, or Factor 1, and noted that the Company identified nine existing CCR projects whose costs are being recovered through Rider E.[75] Mr. Barron contended that SB 1355 does not change the nature of the CCR costs at issue in this case by making them different from CCR costs recovered in Rider E.[76] He noted that SB 1355 requires the costs recovered in Rider CCR to be allocated on a non-bypassable basis, whereas CCR costs recovered through Rider E are allocated only to full service customers. However, he also stated that this difference does not justify a change in the allocation of the CCR costs among customer classes and pointed out that SB 1355 does not require any specific allocation of Rider CCR costs among rate classes.[77]

Next, Mr. Baron disagreed with Company witness Haynes's comparison of SB 1355 to PIPP as a basis for allocation of Rider CCR costs and contended that "[t]he fact that PIPP costs are allocated and recovered from all customers on a uniform $/kWh basis does not support the allocation and recovery of CCR remediation costs on the same basis."[78] He pointed out that § 56-585.6 of the Code specifically requires that PIPP costs be allocated on the basis of kWh usage whereas SB 1355 does not require a specific methodology for recovery of CCR costs. He further contended that the Company did not support its proposed departure from the Commission's prior determination in the 2019 Rider E Order that CCR-related costs are to be allocated using A&E Factor 1.[79]

Lastly, Mr. Baron presented the table below illustrating a comparison of the allocation of the initial Rider CCR revenue requirement using the Company's proposed allocation and his proposed A&E Factor 1 allocation.[80] He noted that the impact on high load customers is

[71] *Id.*
[72] *Id.*
[73] *Id.* at 7.
[74] *Id.*
[75] *Id.* at 8-9.
[76] *Id.* at 9.
[77] *Id.* at 9-10.
[78] *Id.* at 10-11.
[79] *Id.* at 11.
[80] *Id.* at 12.

significant, and calculated that, over the 35-year life of Rider CCR, the dollar impact between the different methodologies on GS-4 customers would be approximately $200 million.[81]

Table 1
Comparison of CCR Revenue Allocation: Uniform $/kWh vs. A&E Factor 1

	Total Va Juris	Residential	GS-1	GS-2	GS-3	GS-4	Churches	Outdoor Lighting
Factor 1 Allocation*	1.00	0.540	0.052	0.148	0.146	0.108	0.005	0.002
CCR 2022 Rev. Req. (allocated on Fac. 1)	$ 216,087	$ 116,637	$ 11,187	$ 32,015	$ 31,652	$ 23,275	$ 980	$ 341
CCR 2022 Rev. Req.** (allocated per DEV)	$ 216,087	$ 87,823	$ 10,594	$ 33,081	$ 40,742	$ 42,918	$ 663	$ 267
Difference (Line 3 - Line 4)		$ (28,814)	$ (593)	$ 1,066	$ 9,089	$ 19,644	$ (317)	$ (74)
% Difference		-24.7%	-5.3%	3.3%	28.7%	84.4%	-32.3%	-21.8%

* Response to VCFUR Set 2-1.
** Schedule 46C, as-filed, adjusted to reflect Amended filing.

STAFF'S DIRECT TESTIMONY

Staff submitted the direct testimony of Sean M. Welsh, Manager with the Commission's Division of Utility Accounting and Finance and Katya Kuleshova, Strategic Planning Specialist with the Commission's Division of Public Utility Regulation.

Mr. Welsh presented Staff's recommended revenue requirement of $220.761 million, but recommended limiting the revenue requirement in this case to the $216.146 million contained in the public notice.[82] He explained that the major difference between Staff's and the Company's revenue requirement is due to Staff's use of the 2020 jurisdictional allocation factor, as opposed to the Company's use of the 2019 jurisdictional allocation factor.[83] He also noted that Staff made minor revisions to the cost of capital, consistent with the agreed-upon capital structure in the Company's other rider cases.[84] He discussed Staff's Rider CCR jurisdictional factors and noted that the inclusion of the 2020 jurisdictional allocation increases the revenue requirement

[81] *Id.*
[82] Ex. 21, at 2-3.
[83] *Id.* at 3.
[84] *Id.*

by \$4.674 million.[85] He discussed the capital structure and cost of capital used to calculate the revenue requirement and confirmed the 6.876% cost of capital includes a 9.2% ROE.[86]

Next, Mr. Welsh provided a brief overview of the accounting-related provisions of SB 1355 and provided a brief description of the typical accounting treatment for asset retirement obligations ("AROs").[87] He stated that the Company uses traditional ARO accounting to account for Rider CCR costs on its books but proposes to recover Rider CCR costs on a cash basis.[88] He confirmed that Staff does not oppose the Company's proposed cash-basis accounting methodology and prepared its recommended revenue requirement using the same methodology.[89] Mr. Welsh recommended that future Rider CCR updates include the balances of the associated per books ARO liabilities and asset retirement cost ("ARC") assets as of the end of each calendar year and the total of any Rider CCR period expenses incurred during the year, including ARO accretion, ARC depreciation, and any related operations and management expense.[90] Mr. Welsh stated that the Company began deferring Rider CCR costs in July 2019 and anticipates incurring \$135 million in Virginia jurisdictional CCR costs prior to December 1, 2021, which the Company proposes to recover over the 12-month Rate Year.[91] Mr. Welsh did not oppose the Company's proposed 12-month amortization period for deferred cost, but given their magnitude (61% of the Rate Year revenue requirement), he stated that the Commission may want to consider a longer amortization period.[92] He acknowledged that this approach would increase carrying costs on the overall revenue requirement and may cause future Rider CCR revenue requirements to exceed the statutory \$225 million annual cap.[93]

Next, Mr. Welsh discussed Staff's audit of actual Rider CCR costs incurred to date and reported that Staff found no material discrepancies in its audit of actual costs.[94] Similarly, Mr. Welsh discussed its review of costs underlying the Company's Projected Factor revenue requirement and did not take issue with the Company's projections in this filing.[95] He confirmed that Staff will continue to review Rider CCR costs as the Company incurs them and noted that any differences between these projections and actual costs incurred will be addressed through a future Rider CCR True-up Factor.[96]

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85 *Id.*
86 *Id.* at 4.
87 *Id.* at 5-6.
88 *Id.* at 6.
89 *Id.*
90 *Id.*
91 *Id.* at 7.
92 *Id.*
93 *Id.* at 7-8.
94 *Id.* at 8.
95 *Id.*
96 *Id.*

Based on the Company's projected costs, Mr. Welsh calculated a total revenue requirement of $2.2 billion, over the 15-year life of Rider CCR.[97] He provided the following table showing the total Rider CCR costs projected for each plant.[98]

Location	Total System CCR Costs (in millions)	Year of Completion
Bremo	$530	2031
Chesapeake	$225	2029
Chesterfield	$1,613	2036
Possum Point	$347	2030
Total	$2,716	

Ms. Kuleshova provided an overview of the Company's Petition and Rider CCR.[99] In addition, she provided an overview of the major legislative acts that have a bearing on the CCR Projects and concluded that "the Company has been carefully and attentively following regulatory developments applicable to the handling of CCR material and acted promptly to comply with the requirements."[100] Attached to her testimony are the Company's responses to Staff's inquiries regarding the Company's analysis of regulatory impact on the scope of work in Rider CCR, along with a list of CCR Projects that stemmed from regulations enacted prior to the adoption of SB 1355 and cost recovery mechanisms for each Project.[101]

Ms. Kuleshova provided a high-level overview of key steps that must be completed for closure by removal and provided a timeline of the CCR Projects.[102] Additionally, she summarized the Company's CCR placement plans for the Chesterfield Power Station,[103] the Bremo Power Station,[104] the Possum Point Power Station,[105] and the Chesapeake Energy Center.[106]

Next, Ms. Kuleshova discussed the Company's planning process and strategic options analysis, including its four significant strategic decisions: (1) commissioning a high-level (Class 5) feasibility study evaluating several "all or nothing" CCR disposal options for each power station that is now serving as one of the key reference documents; (2) selecting two Power Stations from which CCR material will be beneficiated; (3) selecting onsite or adjacent locations for new lined landfills (subject to the respective Counties' approvals) and completing landfill design plans; and (4) determining the degree of vendor involvement and the scope of work for key vendors at the Chesterfield site.[107] In addition, she discussed key tactical decisions made by

[97] *Id.* at 9.
[98] *Id.*
[99] Exs. 22 and 22ES, at 2-4.
[100] *Id.* at 4-14.
[101] *Id.* at 14.
[102] *Id.* at 14-15.
[103] *Id.* at 16-20.
[104] *Id.* at 20-21.
[105] *Id.* at 21.
[106] *Id.* at 22.
[107] *Id.* at 22-23.

the Company and the Company's rationale for beneficiating CCR material from the Chesterfield and Chesapeake Power Stations.[108]

Ms. Kuleshova offered several strategic planning suggestions such as performing an analysis on the feasibility of transporting Rider CCR materials via rail to Virginia City Hybrid Energy Center ("VCHEC"), given that Cells 2A/3B at the Curley Hollow Landfill at VCHEC will be placed into service in the Fall of 2021.[109] Based on Ms. Kuleshova's calculations, there appears to be enough existing capacity at the Curley Hollow Landfill to accommodate all of the ash created by running VCHEC through 2035, and it appears that new Cells 2A/3B may not be needed for VCHEC.[110] In addition, she recommended that the Company consider an array of available technological options for each workstream before awarding significant contracts and include the respective feasibility and cost analyses in future annual Rider CCR filings.[111] Further, she recommended that the Company evaluate emerging beneficiation solutions on an ongoing basis and include the respective feasibility and cost analyses in annual Rider CCR filings.[112] She also recommended that, if a lower cost solution is identified, the Company maintain the flexibility to make changes to its plans to take advantage of any potential cost savings.[113]

Regarding long-term financial planning, Ms. Kuleshova provided the following table illustrating the total estimated cost of the CCR Projects, collectively and at each site and the differences across ponds.[114]

	Total Cost[117]	CCR volume[118]	Cost per cubic yard	Cost % of total	Volume % of total	Cost per cubic yard
	$ million	million cubic yards	$/cubic yard	%	%	% above or below average
Chesterfield LAP	$ 434	2.9	$ 149.69	16%	11%	49%
Chesterfield UAP	$ 1,179	11.9	$ 98.90	43%	44%	-2%
Bremo	$ 530	6.0	$ 88.32	20%	22%	-12%
Possum Point	$ 347	4.0	$ 86.77	13%	15%	-14%
Chesapeake	$ 225	2.2	$ 103.20	8%	8%	3%
Total	$ 2,716	27.0	$ 100.55	100%	100%	

She explained how costs are projected to accumulate over the lifetime of the CCR Projects and discussed how costs compare across sites.[115] She discussed the level of contingency

[108] *Id.* at 23-25.
[109] *Id.* at 25-27.
[110] *Id.* at 27.
[111] *Id.* at 28.
[112] *Id.*
[113] *Id.*
[114] *Id.* at 29.
[115] *Id.* at 29-31.

projected by the Company and stated that it is not consistent with the contingency level of similar projects.[116] She also discussed the financial risk factors of the CCR Projects and identified factors that may lead to actual costs' divergence from the budget.[117] Ms. Kuleshova explained how the Company plans to manage the financial risk factors of the CCR Projects and provided Staff's suggestions on mitigating the financial risks.[118] She confirmed that Staff believes the Company's costs have been prudent up until now.[119]

Next, Ms. Kuleshova discussed the Company's proposed cost allocation and agreed with the Company's proposal to use an energy-based cost allocation methodology.[120] She reported that Staff found precedent in North Carolina and cited to a case wherein the North Carolina Public Utility Commission found and concluded "that the appropriate and reasonable course of action is to allocate the CCR costs by the energy allocation factor."[121] Next, Ms. Kuleshova discussed the impact of the Company's proposed surcharges on customers' bills and provided a table showing the total bill impact for a residential customer using 1,000 kWh that would result from the ten pending rate adjustment clauses.[122]

In conclusion, Ms. Kuleshova recommended that, should the Commission approve a revenue requirement that differs from the Company's requested revenue requirement, the corresponding Rider CCR charges be adjusted consistent with the jurisdictional and class cost allocation methodology approved herein and with the Company's proposed class rate design.[123]

DOMINION ENERGY'S REBUTTAL TESTIMONY

Messrs. Stites, Robertson, and Haynes filed rebuttal testimony on behalf of the Company.

Mr. Stites responded to the recommendations made by Staff witness Kuleshova. First, he proposed an alternative to Ms. Kuleshova's recommendation that the Company be required to conduct a Class 2 study to analyze transporting CCR material by rail from Bremo and Possum Point Power Stations and place it into Cells 2A/3B at the VCHEC Curley Hollow Landfill.[124] He described the purpose of a Class 2 study and the time and cost involved in performing such a study.[125] He stated that a Class 5 study would be sufficient to achieve the financial analysis proposed by Staff and would be less burdensome in terms of time and cost.[126] In addition, he proposed only including the Possum Point facility in the Class 5 study because the time required to conduct such a study would not be aligned with the timeline of ongoing work at the Bremo

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[116] *Id.* at 31.
[117] *Id.* at 31-32.
[118] *Id.* at 33-35.
[119] *Id.* at 35.
[120] *Id.* at 36-38.
[121] *Id.* at 38.
[122] *Id.* at 38-40.
[123] *Id.* at 40.
[124] Ex. 32, at 2-3.
[125] *Id.*
[126] *Id.* at 3.

Power Station.[127] He pointed out that significant time and money has already been committed to the Bremo Landfill.[128]

Mr. Stites disagreed with Staff's assessment that Curley Hollow Cells 2A/3B are not needed for VCHEC operations and explained that landfill capacity is only one consideration even if Cells 2A/3B can receive additional CCR.[129]

Mr. Stites confirmed that the Company considers all available technological options for each workstream as part of its request for proposal ("RFP") process and will continue to do so.[130] He further stated that the Company evaluates emerging beneficiation solutions and seeks lower cost options where feasible.[131] He affirmed that the Company will continue to do so with respect to Rider CCR Projects as it is able within the confines of SB 1355 and contractual obligations.[132]

Lastly, Mr. Stites noted that the Company is agreeable to providing a report of operational and financial milestones for the CCR Projects, as recommended by Staff, but proposed to do so on an annual basis, rather than a biannual basis.[133] In addition, he proposed to include the information with the Company's Rider CCR Annual Update filing.[134] He identified certain reporting items recommended by Staff that may be difficult to report on as Projects progress or may be of little value and requested that, to the extent the Commission directs the Company to provide a report, those items be excluded.[135]

Mr. Robertson responded to Staff witness Welsh's testimony. He clarified that the Company will calculate an Actual Cost True-Up Factor for calendar year 2021 as part of the 2022 update filing and will request such true-up as part of the November 1, 2022 – October 31, 2023 rate year.[136] He agreed with Mr. Welsh's revenue requirement calculation of $220.761 million, including Staff's use of a 2020 allocation factor and 2019 cost of capital. He noted that the updated revenue requirement is higher than the original $216.146 million revenue requirement contained in the public notice, and therefore he agreed with limiting the revenue requirement to the noticed amount.[137]

Next, Mr. Robertson discussed the amortization period for deferred costs. He agreed with Mr. Welsh that the Commission has discretion to direct a different amortization period than the Company's proposed one-year period, but cautioned that implementation of a longer

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[127] *Id.* at 3-4.
[128] *Id.*
[129] *Id.* at 4.
[130] *Id.* at 5-6.
[131] *Id.* at 6.
[132] *Id.*
[133] *Id.* at 7.
[134] *Id.*
[135] *Id.* at 7-8.
[136] Ex. 35, at 2.
[137] *Id.*

amortization period will likely cause future projected revenue requirements to exceed the statutory annual cap of $225 million and could increase carrying costs.[138]

Mr. Haynes responded to the testimony of Staff witness Kuleshova and Committee witness Baron. Mr. Haynes maintained that the Company's proposal to allocate Rider CCR costs on Factor 3 to the jurisdictions and to recover such costs through a uniform charge is consistent with cost causation.[139] However, he recognized that the types of costs being incurred for CCR remediation could be allocated differently and discussed other methodologies he considered.[140] To address the concerns raised by Committee witness Baron, Mr. Haynes presented an alternative hybrid allocation methodology that differentiates between the types of costs that could be plant/facility-related (Factor 1 CCR Non-bypassable) and those that could be related to reusing the CCR material in a recycling process for encapsulated beneficial use (Factor 3 CCR Non-bypassable).[141] In addition, he presented an alternative rate design based on the alternative hybrid allocation methodology whereby certain high-usage customers are billed using the on-peak demand billing determinant while all other customers are billed using the energy (kWh) billing determinant.[142] Mr. Haynes also provided typical bill calculations for the alternative hybrid allocation methodology, the Company's proposed methodology as presented in his Supplemental Schedule 4, and the Committee's proposal to use Factor 1.[143] He provided a table summarizing the cost allocation and rate design methodologies for Rider CCR:[144]

CODE OF VIRGINIA

Section 56-585.1 A 5 e of the Code states as follows:

> A utility may at any time, after the expiration or termination of capped rates, but not more than once in any 12-month period, petition the Commission for approval of one or more rate adjustment clauses for the timely and current recovery from customers of the following costs:
>
> ....
>
> Projected and actual costs of projects that the Commission finds to be necessary ... to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the costs of allowances purchased through a market-based trading program for carbon dioxide emissions. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations....

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[138] *Id.* at 3.
[139] Exs. 36 and 36ES, at 6-9.
[140] *Id.* at 12-13.
[141] *Id.* at 14-16.
[142] *Id.* at 17-18.
[143] *Id.* at 18-19.
[144] *Id.* at 20.

SB 1355, codified as § 10.1-1402.03, provides, in part:

> B. The owner or operator of any CCR unit located within the Chesapeake Bay watershed at the Bremo Power Station, Chesapeake Energy Center, Chesterfield Power Station, and Possum Point Power Station that ceased accepting CCR prior to July 1, 2019, shall complete closure of such unit by (i) removing all of the CCR in accordance with applicable standards established by Virginia Solid Waste Management Regulations (9VAC20-81) and (ii) either (a) beneficially reusing all such CCR in a recycling process for encapsulated beneficial use or (b) disposing of the CCR in a permitted landfill on the property upon which the CCR unit is located, adjacent to the property upon which the CCR unit is located, or off of the property on which the CCR unit is located, that includes, at a minimum, a composite liner and leachate collection system that meets or exceeds the federal Criteria for Municipal Solid Waste Landfills pursuant to 40 C.F.R. Part 258. The owner or operator shall beneficially reuse a total of no less than 6.8 million cubic yards in aggregate of such removed CCR from no fewer than two of the sites listed in this subsection where CCR is located.
>
> C. The owner or operator shall complete the closure of any such CCR unit required by this section no later than 15 years after initiating the closure process at that CCR unit....
>
> D. Where closure pursuant to this section requires that CCR or CCR that has been beneficially reused be removed off-site, the owner or operator shall develop a transportation plan in consultation with any county, city, or town in which the CCR units are located and any county, city, or town within two miles of the CCR units that minimizes the impact of any transport of CCR on adjacent property owners and surrounding communities. The transportation plan shall include (i) alternative transportation options to be utilized, including rail and barge transport, if feasible, in combination with other transportation methods necessary to meet the closure timeframe established in subsection C, and (ii) plans for any transportation by truck, including the frequency of truck travel, the route of truck travel, and measures to control noise, traffic impact, safety, and fugitive dust caused by such truck travel. Once such transportation plan is completed, the owner or operator shall post it on a publicly accessible website. The owner or operator shall provide notice of the availability of the plan to the Department and the chief administrative officers of the consulting localities and shall publish such notice once in a newspaper of general circulation in such locality.
>
> *****
>
> H. All costs associated with closure of a CCR unit in accordance with this section shall be recoverable through a rate adjustment clause authorized by

> … the Commission under the provisions of subdivision A 5 e of § 56-585.1, provided that (i) when determining the reasonableness of such costs the Commission shall not consider closure in place of the CCR unit as an option; (ii) the annual revenue requirement recoverable through a rate adjustment clause authorized under this section, exclusive of any other rate adjustment clauses approved by the Commission under the provisions of subdivision A 5 e of § 56-585.1, shall not exceed $225 million on a Virginia jurisdictional basis for the Commonwealth in any 12-month period, provided that any under-recovery amount of revenue requirements incurred in excess of $225 million in a given 12-month period, limited to the under-recovery amount and the carrying cost, shall be deferred and recovered through the rate adjustment clause over up to three succeeding 12-month periods without regard to this limitation, and with the length of the amortization period being determined by the Commission; (iii) costs may begin accruing on July 1, 2019, but no approved rate adjustment clause charges shall be included in customer bills until July 1, 2021; (iv) any such costs shall be allocated to all customers of the utility in the Commonwealth as a non-bypassable charge, irrespective of the generation supplier of any such customer; and (v) any such costs that are allocated to the utility's system customers outside of the Commonwealth that are not actually recovered from such customers shall be included for cost recovery from jurisdictional customers in the Commonwealth through the rate adjustment clause.

In addition, pursuant to § 56-585.1 A 7 of the Code, the Commission is required to enter its final order on the Petition not more than eight months after the filing date of the Petition. Additionally, § 56-585.1 A 7 of the Code requires that the Commission's final order direct that the applicable RAC be applied to customers' bills not more than 60 days after the date of the final order.

DISCUSSION

This is the first Rider CCR case before the Commission. Although there are only two disputed issues, there are several other issues that were raised and warrant discussion. The unopposed issues include: (1) the revenue requirement; (2) the amortization period for deferred costs; and (3) additional reporting requirements to be included with Rider CCR Annual Update filings. The disputed issues are: (1) the cost allocation methodology for Rider CCR; and (2) whether the Company should be required to perform additional studies to assess the feasibility of transporting CCR material via rail from the Bremo and Possum Point Power Stations to Cells 2A/3B at the Curley Hollow Landfill.

Revenue Requirement

No participant challenged whether the CCR Projects are appropriate for recovery under § 56-585.1 A 5 e and § 10.1-1402.03 of the Code or whether the CCR removal costs incurred to date were reasonable or prudently incurred. In its Petition, the Company proposed a $216.146

million Rider CCR revenue requirement. In its calculation of the revenue requirement, Staff incorporated a 2020 jurisdictional allocation factor for Rate Year costs, which resulted in a revenue requirement of $220.761 million.[145] Consistent with Commission precedent, Staff recommended limiting the revenue requirement to $216.146 million, the amount in the Petition and the public notice.[146] The Company agreed with Staff's recommendation, the Committee did not take a position on the revenue requirement, and Consumer Counsel did not oppose the revenue requirement.[147] I find the Company's unopposed revenue requirement is reasonable and supported by the record of this case. Therefore, I recommend the Commission approve a Rider CCR revenue requirement of $216.146 million for the Rate Year.

Amortization Period

With respect to the amortization period for deferred costs, the Company proposed a 12-month period, with no financing costs to be recovered. Staff did not oppose the Company's recommended amortization period, but, given the magnitude (61% of the Rate Year revenue requirement) of the deferred costs, suggested that the Commission may want to consider a longer amortization period.[148] However, Staff acknowledged that this approach would increase carrying costs on the overall revenue requirement and may cause future Rider CCR revenue requirements to exceed the statutory $225 million annual cap.[149] The Company agreed that the Commission has discretion to extend the amortization period, but, echoing Staff's concerns associated with a longer amortization, maintained that a 12-month amortization period is appropriate in this case. I find the Company's proposed 12-month amortization period for deferred costs reasonable.

Reporting Requirements

Operational and Financial Milestones

Staff recommended that the Company be required to report certain operational and financial milestones of the CCR Projects to the Commission every six months.[150] The Company agreed to provide the information but proposed doing so annually, rather than biannually.[151] The Company further recommended including the information with the Company's Rider CCR Annual Update filings.[152] In addition, the Company identified certain reporting items recommended by Staff that may be difficult to report on as Projects progress or may be of little value and requested that, to the extent the Commission directs the Company to provide a report, those items be excluded.[153] At the hearing, Staff did not oppose the Company's modifications to Staff's proposed reporting requirements. Ms. Kuleshova testified that "Staff believes that the

[145] Ex. 21, at 2-3.
[146] *Id.* at 3.
[147] *See e.g.*, Ex. 35, at 2; Tr. at 13, 24.
[148] Ex. 21, at 7.
[149] *Id.* at 7-8.
[150] Exs. 22 and 22ES, at 34-35.
[151] Ex. 32, at 7.
[152] *Id.*
[153] *Id.* at 7-8.

modified reports will be beneficial for tracking the progress of the CCR [P]rojects."[154] I agree and therefore find that the information proposed to be included in the modified reports will be beneficial for tracking the progress of the CCR Projects. Accordingly, I recommend that the Company be required to include with its Rider CCR Annual Update filing the modified reports containing the information agreed upon by the Company and Staff.

Emerging Beneficiation Solutions

Consistent with § 10.1-1402.03 E of the Code, Staff recommended the Company evaluate emerging beneficiation solutions on an ongoing basis and include the respective feasibility and cost analyses in future Rider CCR Annual Update filings.[155] Staff further recommended the Company "maintain the flexibility to make changes to its plans to take advantage of any potential cost savings" if a lower cost solution is identified.[156]

Company witness Stites testified that the Company's analysis "always considers and evaluates lower cost options," but SB 1355 "restrict[s] the beneficiation solutions available to the Company."[157] Although Mr. Stites stated that, once selected beneficiation options are locked in, the beneficiation options "could not then be revisited without breaking contracts and incurring substantial costs[,]" the Company agreed that if lower cost options are determined to be technically feasible and can be implemented subject to statutory requirements and executed Company contracts, the Company will reflect the associated savings in reduced project estimates.[158] Accordingly, I find the Company should be required to reflect the associated savings in reduced project estimates if it determines that lower cost options related to beneficiation solutions are technically feasible and can be implemented subject to statutory requirements and executed Company contracts.

Feasibility and Cost Analyses

Staff also recommended that the Company "consider an array of available technological options for each workstream before awarding significant contracts and include the respective feasibility and cost analysis in future Rider CCR [Annual Update] filings."[159] In response, the Company asserted that the assessment of available technological options for each work stream is imbedded in the Company's existing competitive bid process and was one of the considerations that factored into awarding the contracts associated with the CCR Projects.[160] At the hearing, Staff witness Kuleshova explained that the information included with the Petition "did not have the level of granularity that allows for meaningful comparative analysis of technological options for each workstream."[161] She explained that, if the information were provided with the Rider

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[154] Tr. at 170-71.
[155] Exs. 22 and 22ES, at 28.
[156] *Id.*
[157] Ex. 32, at 6.
[158] *Id.*
[159] Exs. 22 and 22ES, at 28.
[160] Ex. 32, at 5.
[161] Tr. at 168.

CCR Annual Update filing, the parties and Staff would have more time to thoroughly investigate the information.[162] At the hearing, Company witness Stites testified that the Company would be willing to provide the requested information, when it has been through the RFP process between Rider CCR Annual Update filings.[163] He clarified that the information would be extraordinarily sensitive.[164] I find that the Company should include with its Rider CCR Annual Update filings the technological options it considered for each workstream for the significant contracts it awards, including the respective feasibility and cost analyses.

Cost Allocation Methodology and Rate Design

The CCR material that is the subject of Rider CCR is "legacy" coal ash.[165] It is the byproduct of years (and even decades) of burning coal at the Power Stations.[166] The last batch of CCR material associated with Rider CCR was placed into storage in February 2018.[167] Usually, the Company's rates recover "current period costs or costs that are applicable to a certain period, or projected costs;" however, when the CCR material at issue here was produced, SB 1355's more stringent requirements for the remediation of the legacy coal ash were not in place.[168] Thus, the Company did not incur or recover the remediation costs when the CCR material was produced.[169]

Through Rider CCR, the Company must now collect from its current customers the cost of remediating the CCR material created from providing service to past customers. According to Company witness Haynes, "[t]he scope and nature of the work required by SB 1355 and the resulting cost is caused by the volume of CCR material to be removed and either beneficiated or relocated, and presents a novel and unique cost allocation situation for the Company and the Commission."[170]

In its Petition, the Company proposed to allocate the Rider CCR costs to the Virginia jurisdiction using the Factor 3 CCR Non-bypassable cost allocator that considers the energy usage at production level for all Virginia jurisdictional customers, irrespective of generation supplier.[171] In addition, Factor 3 CCR Non-bypassable includes all other entities to which the Company has an obligation to provide generation service.[172] According to the Company, its

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[162] *Id.*
[163] Tr. at 230-31.
[164] Tr. at 230.
[165] Mr. Haynes defined "legacy" coal ash as follows: "ash related to meeting [the Company's] consumption or [ ] obligation to serve customers in the past. It doesn't relate to current production and output of ash to serve present customers and their demand in energy requirements." Tr. at 109.
[166] Tr. at 99.
[167] *Id.*
[168] Tr. at 99-100.
[169] Tr. at 100.
[170] Ex. 13, at 4.
[171] *Id.* at 5.
[172] *Id.* at 5-6.

method of using energy at production level "recogniz[es] energy loss differences associated with serving customers within the individual jurisdictions at different service voltages."[173] Using this methodology, the Company calculated a Virginia jurisdictional allocation of 79.1397%.[174] Company witness Haynes compared this amount with Factor 3 for the Virginia jurisdiction from 2001 through 2019, which revealed a range between 77.2615% and 78.9585%.[175]

With respect to the Rider CCR rate, the Company proposed recovering the revenue requirement from all customers using a uniform charge per kWh, irrespective of their generation supplier.[176] In support of the proposed uniform charge per kWh rate, Mr. Haynes compared SB 1355's requirement that Rider CCR costs be allocated to all jurisdictional customers with the General Assembly's recent policy determination that the PIPP universal service fee be recovered from all customers using a uniform charge per kWh.[177] He concluded that "[l]ike the PIPP uniform charge, the Company's proposed recovery of Rider CCR costs through a uniform charge per kWh for all Virginia jurisdictional customers is appropriate given its context as a matter of policy."[178]

Further, Mr. Haynes testified that the Company's proposed allocation methodology "appears to be reasonable and equitable (as well as straightforward)" because "it yields a result in line with historic energy usage relationships and is related to the coal used to fuel the [P]ower [S]tations."[179] Consumer Counsel agreed "that, because the volume of CCR material accumulated at the facilities subject to SB 1355 is directly correlated with the amount of fuel burned over many years, allocating costs on an energy basis is consistent with cost causation and is therefore reasonable and equitable."[180] Similarly, Staff agreed with the Company's rationale for its proposed cost allocation methodology and stated "[t]he Company's proposal to match costs required by SB 1355 with how benefits were received by past customers is appropriate under these circumstances and should be approved."[181]

The Committee disagreed with the Company's proposed uniform charge per kWh for Rider CCR and the Company's reliance on the PIPP legislation in support of its proposed methodology. Committee witness Baron pointed out that the PIPP legislation expressly provides that PIPP costs be "allocated...on the basis of the amount of [kWh] used...."[182] In contrast, SB 1355 contains no such provision. The Committee also asserted that SB 1355's beneficiation requirement does not warrant a change in cost recovery and that "[t]he only thing that

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[173] *Id.* at 6.
[174] Ex. 14, at 2.
[175] Ex. 13, at 4-5, Schedule 6.
[176] *Id.* at 6.
[177] *Id.* at 7.
[178] *Id.*
[179] *Id.* at 4; Tr. at 100-01.
[180] Consumer Counsel Brief, at 6.
[181] *See e.g.*, Exs. 22 and 22ES, at 17; Staff's Post-Hearing Brief, at 28.
[182] Ex. 20, at 11; 2019 Va. Acts, Ch. 651.

distinguishes the CCR at issue in this case from all other Dominion CCR is where it is <u>currently</u> located...."[183]

Moreover, the Committee asserted that the Company's proposed Rider CCR allocation methodology "is unreasonable, not based on cost causation, inconsistent with efficient pricing, and inconsistent with the Commission's decision in the Company's Rider E case ... regarding the recovery of similar CCR costs."[184] Committee witness Baron characterized the CCR costs as fixed production costs that are being incurred to operate the Company's system.[185] Mr. Baron stated that these types of costs are traditionally allocated using the Factor 1 methodology.[186] Therefore, he recommended that Factor 1 be used to allocate Rider CCR costs to rate classes.[187]

Mr. Baron testified:

> The CCR output of these coal plants is a function of the portion of each unit's capacity being operated and the number of hours of that operation. That's a physical reality. If the coal unit never ran, there would be no CCR. And that indisputable fact has been the case for many years, as the CCR was routinely produced at the same coal units and stored in their on-site facilities. Yet over these many years, the costs of these CCR related facilities have been allocated on a demand basis using Factor 1.[188]

Further, the Committee stressed that allocating Rider CCR costs based on non-loss adjusted, metered energy usage is inconsistent with cost causation and cost of service principles.[189] Additionally, the Committee argued that the Company's proposed allocation methodology sends customers price signals that are not economically efficient.[190] Mr. Baron explained that the Company's methodology "implies that the CCR costs at issue are driven by customer energy usage, regardless of when it occurs[,]" but in fact, if a customer curtails its off-peak energy usage, there would be no reduction in the CCR costs being recovered through Rider CCR because those costs are fixed remediation costs.[191]

The Committee noted instances where the Commission has rejected the use of Factor 3 to allocate environmental compliance costs, including handling of CCR material, and highlighted instances where the Commission has approved recovery of CCR-related costs using Factor 1, including the Company's Rider E.[192] In addition, the Committee disagreed with the Company's

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[183] Committee's Post-Hearing Brief, at 22, 26. SB 1355 specifically applies to CCR units within the Chesapeake Bay watershed.
[184] Ex. 20, at 5-6.
[185] *Id.* at 7.
[186] *Id.* at 5.
[187] *Id.* at 5-6.
[188] Tr. at 122-23.
[189] Ex. 20, at 6.
[190] *Id.*
[191] *Id.*
[192] *Id.* at 6, 8-9; Committee's Post-Hearing Brief at 3-7.

distinction between legacy and current CCR material for purposes of allocating costs and argued that there is "no bright line distinction between certain Rider E and Rider CCR costs."[193] In support of its position, the Committee focused on the similarities between Rider CCR and Rider E. For example, the Committee pointed out that "Rider CCR would recover costs to construct new lined landfills; as does Rider E....Rider CCR would recover water treatment costs; so does Rider E. Rider CCR would recover costs to de-water ash ponds; so does Rider E."[194] The Committee also highlighted the fact that Cell 1 costs at the Chesterfield Station Landfill are being recovered through Rider E, while Cells 2, 3, and 4 costs at the Chesterfield Station Landfill are proposed for recovery through Rider CCR.[195] Additionally, the Committee noted that the Curley Hollow Landfill, which Staff is recommending be considered for placement of the CCR material from Bremo and Possum Point, is recovered through Rider S and allocated using Factor 1.[196]

On the other hand, the Company, Consumer Counsel, and Staff focused on the differences between Rider CCR and Rider E. For example, Rider E environmental projects are necessary to enable the Company to maintain its capacity obligation and to have these resources available to serve current customer's energy and capacity requirements,[197] whereas Rider CCR environmental projects are necessary to comply with SB 1355's requirement that the Company remove and dispose of or beneficiate legacy coal ash that was created by burning coal to meet prior customer's energy needs.[198] Another distinction between Rider E and Rider CCR is that they were developed to comply with different environmental laws and regulations. For example, Rider E was developed to comply with the EPA's CCR Rule and the Effluent Guidelines, promulgated under the Clean Water Act, whereas Rider CCR was developed to comply with SB 1355.[199] In addition, unlike Rider CCR, Rider E is not limited to recovery for CCR Projects.[200] Moreover, CCR material addressed in Rider CCR is location-specific to the Chesapeake Bay watershed.[201] Staff witness Kuleshova also noted that the accounting treatment for Rider E is on an accrual basis, whereas Rider CCR is on a cash basis; Rider E costs are bypassable, whereas Rider CCR costs are non-bypassable; and Rider E costs must meet the environmental requirements at least costs, whereas Rider CCR does not have a least cost limitation.[202]

Consumer Counsel and Staff each pointed to North Carolina Utilities Commission cases where recovery of CCR costs were approved based on an energy allocator.[203] The Committee referenced a recent decision in West Virginia that based recovery of CCR Projects on a demand

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[193] Committee's Post-Hearing Brief, at 20. *See also,* Tr. at 134-35.
[194] Committee's Post-Hearing Brief, at 22.
[195] *See e.g.,* Ex. 20, Exhibits (SJB-2) and (SJB-3); Exs. 3 and 3ES, at 9.
[196] Ex. 5, at 3.
[197] *See e.g.,* Tr. at 76-77, 93, 182.
[198] Tr. at 108-10, 196-97.
[199] Tr. at 93-94, 110, 196-97.
[200] Tr. at 114-15.
[201] Tr. at 104, 196-97.
[202] Tr. at 196-97.
[203] *See e.g.,* Exs. 22 and 22ES, at 37-38; Ex. 37.

allocator.[204] The Committee argued that "[c]onflicting orders from North Carolina do not justify a departure from Virginia precedent[]" and urged the Commission to consider "its own, more relevant and recent precedent for guidance in this matter."[205]

The Company acknowledged that there are other ways in which the CCR remediation costs at issue could be allocated.[206] Therefore, Mr. Haynes performed additional analysis of Factor 3 and comparisons with Factor 1.[207] In addition to the 2001 through 2019 historical Factor 3 Virginia jurisdictional comparison discussed above, Mr. Haynes performed an analysis considering Factor 3 for each customer class within the Virginia jurisdiction.[208] He compared the 2019 Factor 3 percent of system to the historical Factor 3 percent of system for 2000 through 2017 to evaluate the 2019 Factor 3's effectiveness in allocating cost responsibility with cost causation.[209] He concluded that there is consistency among most customer classes, except GS-2 and GS-4.[210] He further stated that the present 2019 Factor 3 "seems to allocate too much to the GS-4 class."[211]

To address this issue, the Company proposed a hybrid methodology for the Commission's consideration.[212] Through its hybrid methodology, the Company attempted to drill down further into the underlying cause for costs within the CCR Projects. The Company differentiated the types of CCR costs based on whether they stem from designing, constructing, and maintaining facilities, such as landfills and ash handling equipment and systems (Category 1), or whether they stem from excavating and transporting the volume of ash to either new landfills or to be recycled, and are associated with reusing and recycling the CCR material that are netted against the revenue associated with the sale of such material (Category 2).[213] Under the hybrid methodology the Category 1 costs are allocated using Factor 1 CCR Non-bypassable and Category 2 costs are allocated using Factor 3 CCR Non-bypassable.[214] Based on the costs incurred for 2019-2021 and the Rate Year, the hybrid methodology allocates 28.5596% of the costs using Factor 1 CCR Non-bypassable and 71.4404% of costs using Factor 3 CCR Non-bypassable.[215]

Mr. Haynes also proposed an alternative rate design methodology that is consistent with the Company's generation riders and Rider E and provides that GS-3 and GS-4 customers, affiliated market-based rate customers, and GS-2 and GS-2T customers with greater than a 50%

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204 Committee's Post-Hearing Brief, at 24.
205 *Id.* at 23, 24; *See also,* Tr. at 132-33.
206 *See e.g.,* Ex. 13, at 4; Exs. 36 and 36ES, at 12; Tr. at 14-15.
207 Exs. 36 and 36ES, at 8-11.
208 *Id.* at Rebuttal Schedule 1, p. 1.
209 *Id.* at 11.
210 *Id.*
211 *Id.*
212 *Id.* at 12-20.
213 *Id.* at 14-15.
214 *Id.* at 15-16.
215 *Id.* at 15.

load factor be billed using the on-peak demand billing determinant.[216] All remaining customers would be billed using the energy (kWh) billing determinant.[217] He presented the following summary of cost allocation and rate design alternatives:[218]

Table 7: Summary of Cost Allocation and Rate Design Alternatives

	Cost Allocation Methodology	Rate Design Methodology	Source	Support	Bill Impact
1.	Energy Allocation Using Factor 3 CCR Non-bypassable	Uniform Rate Per kWh Applicable to all Rate schedules	Company Direct Testimony, Supplemental Testimony, Rebuttal Testimony	Staff Pre-filed Testimony	Residential 1,000 kWh = $2.94 GS-4 10,000 kW / 6 mil kWh = $17,664
2.	Factor 1 CCR Non-bypassable (A&E)	Opposed to Uniform Rate Per kWh; Advocates to Not Depart from Methodology Used in Rider E	VCFUR Direct Testimony of Witness Stephen J. Baron		Residential 1,000 kWh = $3.91 GS-4 10,000 kW / 6 mil kWh = $9,840
3.	Alternative Hybrid Methodology Utilizing Factor 1 CCR Non-bypassable (A&E) and Factor 3 CCR Non-bypassable (Energy)	Rate Design Consistent with Rider E; Recovers Cost for Rate Schedules GS-3 and GS-4 through Demand Charge	Company Rebuttal Testimony		Residential 1,000 kWh = $3.33 GS-4 10,000 kW / 6 mil kWh = $13,780

No party or Staff supported the hybrid methodology.[219] Among other things, the Committee asserted that the hybrid methodology shares the originally proposed methodology's fundamental flaw of using an energy allocator to assign fixed costs.[220] Whereas, the Company, Consumer Counsel and Staff maintained that the originally proposed methodology is consistent with cost causation.[221]

As noted previously, this is the first case filed pursuant to SB 1355, codified as Virginia Code § 10.1-1402.03. Although § 10.1-1402.03 H of the Code provides that any costs associated with closure of a CCR unit "shall be allocated to all customers of the utility in the Commonwealth as a non-bypassable charge, irrespective of the generation supplier of any such customer[,]" it does not require that a specific methodology be used to allocate Rider CCR costs. The Commission, therefore, has discretion to determine what allocation methodology should be used to allocate Rider CCR costs.

I agree with the Company that the costs associated with SB 1355 present a novel cost allocation situation for the Company and the Commission.[222] The CCR material at issue in this case is a byproduct of burning coal to meet the generation needs of the Company's past

[216] *Id.* at 17.
[217] *Id.*
[218] *Id.* at 20.
[219] *See e.g.*, Tr. at 15-16, 22, 30, 120-22, 125-26, 128, 130-32, 148-49; Company's Post-Hearing Brief, at 15; Committee's Post-Hearing Brief, at 26-31; Staff's Post-Hearing Brief, at 31.
[220] Tr. at 130-32.
[221] *See e.g.*, Consumer Counsel's Post-Hearing Brief, at 6; Staff's Post-Hearing Brief, at 31.
[222] *See e.g.*, Ex. 13, at 4; Tr. at 99-100.

customers, yet the costs incurred by the Company to comply with SB 1355 must now be collected from the Company's current customers. These costs are not being incurred to meet the Company's obligation to provide energy and capacity needs to its current customers. Therefore, I agree with the Company, Consumer Counsel, and Staff that there is a distinction between the legacy coal ash and the Projects that are the subject of Rider CCR and CCR material and the environmental projects addressed in other rate mechanisms, such as Rider E and base rates. Further, I agree that prior Commission decisions addressing cost allocation of CCR-related projects do not bind the Commission in this case.[223]

I agree with the Company, Consumer Counsel and Staff that there is a direct connection between the volume of CCR materials to be remediated pursuant to SB 1355 and the volume of fuel that was burned at the four Power Stations over many years. The record establishes that fuel-related costs are generally allocated on an energy basis[224] and that a uniform energy rate to recover all CCR remediation costs is consistent with past fuel cost recovery.[225] It follows that allocating the Rider CCR costs on an energy basis is consistent with cost causation. The record further shows that, although high load customers may experience greater costs under a uniform energy charge, they also experience a greater share of energy benefits compared to other customer classes.[226] Allocating Rider CCR costs based on Factor 3 better matches the current costs related to the legacy coal ash remediation and the benefits linked to the prior burning of coal.[227] Accordingly, I find the Company's proposed Factor 3 CCR Non-bypassable allocation methodology and its uniform charge per kWh is reasonable and equitable and, therefore, recommend approval thereof.

<u>Rail Option Studies</u>

To explore options that might decrease SB 1355 compliance costs, Staff recommended the Company conduct a Class 2 study to evaluate the feasibility of constructing a spur from the existing rail line near VCHEC to the Curley Hollow Landfill and transporting via rail CCR material from Bremo and Possum Point Power Stations to the new Cells 2A/3B at the Curley Hollow Landfill at VCHEC. Cells 2A/3B will be placed into service in the Fall of 2021, with a capacity of 14.2 million cubic yards.[228] It is undisputed that there will likely be enough capacity at the Curley Hollow Landfill to receive the CCR material from Bremo, Possum Point, and the ash produced from running VCHEC through 2035.[229] Costs associated with the Curley Hollow Landfill are already being recovered from the Company's ratepayers through Rider S.[230] Transporting the CCR material to the Curley Hollow Landfill would alleviate the need to

[223] Tr. at 93-94.
[224] *See e.g.*, Exs. 36 and 36ES, at 16; Tr. at 102-03, 200-01, 242.
[225] Exs. 36 and 36ES, at 7.
[226] *Id.* at 17; Tr. at 101-02. Mr. Haynes confirmed that, in the past when coal was burned to produce the CCR material, high load customers received greater energy benefits than residential customers. Tr. at 100-01.
[227] Tr. at 101-02.
[228] Exs. 22 and 22ES, at 25, Attachment KK-35; Tr. at 161.
[229] Exs. 22 and 22ES, at 27; Tr. at 223, *See also* Ex. 27C.
[230] Ex. 5, at 3.

construct the proposed landfills at Bremo and Possum Point. As of December 2020, the Company has spent only $12.6 million of the $529.9 million total budget for the Bremo Project and $3.7 million of the total $347.1 million budget for the Possum Point Project.[231] The estimated cost of the Class 2 study is $600,000,[232] approximately 0.07% of the $877 million anticipated combined total cost for the Bremo and Possum Point Projects.[233] Consumer Counsel supported Staff's recommendation.[234]

The Company opposed Staff's recommendation and stated several logistical concerns it had related to Staff's Rail Option. Despite those concerns, the Company proposed an alternative option for the Commission's consideration. The Company's proposal differed from Staff's proposal in two ways. First, the Company proposed to conduct a Class 5 study, rather than the Class 2 study proposed by Staff. Next, the Company proposed to only include Possum Point in the study, instead of both Bremo and Possum Point, as proposed by Staff.[235]

Logistical Challenges

Mr. Stites testified that Staff's Rail Option presented several logistical challenges for the Company. Generally, those challenges involved lacking infrastructure, transportation contracts, rugged terrain near VCHEC, and additional handling associated with transporting CCR material to the Curley Hollow Landfill by rail.[236] Specifically, Mr. Stites noted that Staff's proposal would require construction of load-out facilities at Bremo and Possum Point and that transporting CCR material by rail would involve contracting with two different rail companies.[237] The Company also pointed out that rail siding would need to be designed and constructed at the Curley Hollow Landfill and VCHEC and that the varied terrain of the area would pose significant challenges, if such construction is even possible.[238] Mr. Stites stated that a trucking component would most likely still be required, even if rail siding was extended to the Curley Hollow Landfill.[239] He also surmised that rail sidings could be located offsite, but that too would require a trucking component, and the trucks would have to travel through nearby towns to get to the Curley Hollow Landfill.[240] Further, the Company raised concerns about the additional handling that would be involved under Staff's Rail Option.[241] Mr. Stites stated that, generally, the more the CCR material is handled, the higher the expense and the greater the environmental impact.[242]

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[231] Exs. 3 and 3ES, at 8, 16.
[232] Ex. 23.
[233] Staff's Post-Hearing Brief, at 17-18.
[234] Consumer Counsel's Post-Hearing Brief, at 13-14.
[235] Ex. 32, at 2-4.
[236] Logistical challenges impacting the timing of the construction Projects will be discussed below.
[237] Tr. at 223-24.
[238] Tr. at 224-25.
[239] Tr. at 225.
[240] *Id.*
[241] Tr. at 227-29.
[242] Tr. at 227-28.

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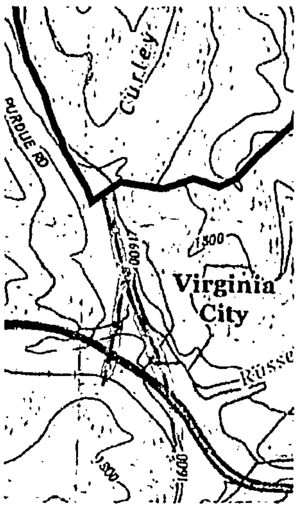
Although Mr. Stites had concerns regarding the challenges of extending a spur directly to VCHEC or the Curley Hollow Landfill because of the rugged terrain in the area, Staff witness Kuleshova highlighted testimony from the Company's VCHEC CPCN Case where a Company witness testified that "key in the selection of [the VCHEC] site was its proximity to and availability of adequate fuel and accessibility to roads, rail, and water supply infrastructure."[243] Additionally, Staff presented a topographical map of the VCHEC site and surrounding areas.[244] The topographical map showed a flat area extending from the existing rail to the VCHEC facility that could potentially accommodate a rail spur.



With respect to the Company's concerns about the impact to public roads, Staff contended that, if it is possible to construct the spur, then no CCR material would need to be transported by truck from an off-site rail transfer location to VCHEC.[245] Further, Staff pointed out that Mr. Stites acknowledged Staff's Rail Option would have no impact on public roads at Bremo.[246] Moreover, Staff noted that construction activity under the Company's current plans would impact public roads at both Bremo and Possum Point, and the construction is anticipated to take at least four years at Bremo and two and a half years at Possum Point.[247] Staff asserted that, if it is possible to build the rail spur at VCHEC, the impact on public roads might be less overall than the impacts of constructing landfills at Bremo and Possum Point.[248]

[243] Exs. 22 and 22ES, at 25-26, quoting *Application of Virginia Electric and Power Company, For a certificate of public convenience and necessity to construct and operate an electric generation facility in Wise County, Virginia, and for approval of a rate adjustment clause under §§ 56-585.1, 56-580 D, and 56-46.1 of the Code of Virginia,* Case No. PUE-2007-00066, ("VCHEC CPCN Case"), Direct Testimony of Robert M. Bisha at 2 (July 13, 2007).
[244] Ex. 29.
[245] Staff's Post-Hearing Brief, at 20, citing Exs. 22 and 22ES, at 25-26; Ex. 29; Tr. at 164-66.
[246] Staff's Post-Hearing Brief, at 21, citing Ex. 28; Tr. at 229.
[247] *Id.* at 21-22, citing Exs. 3 and 3ES, at 15; Exs. 22 and 22ES, Attachment KK-28 at 6, Attachment KK-17.
[248] Staff's Post-Hearing Brief, at 22.

Staff disagreed with the Company's assertions that additional handling would be required under Staff's Rail Option and contended that if it is possible to construct the rail spur directly to the VCHEC facility, the additional handling may be eliminated. Staff reiterated that this issue would be thoroughly evaluated in a Class 2 study.[249]

The Company anticipates spending a combined total of approximately $877 million to construct the Bremo and Possum Point Landfills. Staff presented credible evidence showing the Curley Hollow Landfill has capacity to accommodate the CCR material currently at Bremo and Possum Point.[250] If Staff's Rail Option is feasible, and if the cost analysis is favorable, the Bremo and Possum Point Landfills would not be needed. Therefore, I find that a study to consider other options is warranted and reasonable.

Type of Study

Staff's Rail Option proposes the Company perform a Class 2 study, whereas the Company's alternative option proposes a Class 5 study be performed. Below is an excerpt of Exhibit 23, which illustrates the differences between the classes of studies.

Cost Estimate Classification Matrix

Table TM5-7 from the SB 1398 Report							
Estimate Class	Level of Project Definition[1]	End Usage[1]	Methodology[1]	Expected Accuracy Range[1]	Preparation Effort[1]	Expected Range of Price and Duration to Develop Class Estimates	
						Upper Ranage of the Cost Estiamte	Timeframe
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: −20% to −50% H: +30% to +100%	1	$ 30,000	1 mo
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: −15% to −30% H: +20% to +50%	2 to 4	$ 120,000	2-4 mos
Class 3	10% to 40%	Budget, authorization, or control	Semi-detailed unit costs with assembly level line items	L: −10% to −20% H: +10% to +30%	3 to 10	$ 300,000	4-6 mos
Class 2	30% to 70%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: −5% to −15% H: +5% to +20%	4 to 20	$ 600,000	6-9 mos
Class 1	50% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: −3% to −10% H: +3% to +15%	5 to 100	$ 3,000,000	9-12 mos

The Company stated concerns regarding the amount of time a Class 2 study would require. Unlike the Company's preferred Class 5 study, which would take approximately one month to complete, a Class 2 study would take six to nine months to complete. According to the Company, a delay of six to nine months "would materially delay the projects and introduce considerable risk with respect to the permitting timeline."[251] Mr. Stites testified that the Company is trying to balance the sequencing of Projects over the regulatory schedule set forth in

[249] *Id.* at 22-23.

[250] Ex. 27C.

[251] Company's Post-Hearing Brief, at 16-17, citing Ex. 23; Tr. at 213, 218-19.

SB 1355[252] to avoid stacking more investment out into the latter years of the regulatory schedule.[253] In addition, he reported that the Company has initiated the DEQ permitting process for Bremo and anticipates that process will take approximately two years.[254] He testified that, if the Company is directed to include Bremo in the study, it would need to notify DEQ that it is considering other options, which might cause DEQ to pause its review of the Company's permit application.[255] Mr. Stites also questioned whether a Class 2 study would be complete prior to the filing date for the Company's 2022 Rider CCR filing.[256]

Mr. Stites testified that a Class 5 study is a screening mechanism to evaluate a defined concept that would look at the rail capabilities, the infrastructure and relative costs.[257] He contended that it "should give a good picture for comparison's sake."[258]

Staff opposed the Company's alternative proposal to conduct a Class 5 study, rather than a Class 2 study and provided a high-level outline of the goals of a Class 2 study:

> (1) [D]efine the scope of work and allow the Company to proceed with the RFP process upon completion of the Study; (2) obtain a more precise financial estimate; (3) determine whether Staff's Rail Option may achieve a lower overall cost of the CCR Projects; and (4) reduce overall time between the project studies and execution.[259]

Staff contended that a Class 5 study would not be sufficient to confirm or change a decision to spend hundreds of millions of dollars.[260] First, Staff pointed out that a Class 5 study is only a high level "concept screening" analysis.[261] Staff noted that a Class 5 study includes "judgment" and "analogy" rather than the "significant amount of engineering analysis" a Class 2 study would provide.[262] In addition, Staff pointed out that a Class 2 study "would provide a detailed financial estimate[,]"[263] whereas a Class 5 study would produce a ballpark estimate that could underestimate costs by as much as 50% or overestimate costs by as much as 100%.[264]

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[252] SB 1355 requires that such closure shall be completed "no later than 15 years after initiating the closure process at the CCR unit." *See* § 10.1-1402.03 C. The Company initiated closure of Bremo in March 2019. *See e.g.,* Tr. at 65, 152. The Company anticipates construction at Possum Point to begin late 2023 and be completed by the end of 2029 or beginning of 2030. Tr. at 236.

[253] Tr. at 219-20.

[254] Tr. at 218-19.

[255] *Id.*

[256] Tr. at 216-17.

[257] *See e.g.*, Ex. 32, at 3; Tr. at 214.

[258] Tr. at 214.

[259] Staff's Post-Hearing Brief, at 12-13, citing Tr. at 151-52.

[260] *Id.* at 13; Tr. at 151.

[261] Staff's Post-Hearing Brief, at 13, citing, Ex. 23; Ex. 32, at 3; Tr. 150-51.

[262] *See e.g.,* Ex. 23; Ex. 32, at 2; Tr. at 151-52, 234.

[263] Staff's Post-Hearing Brief, at 14, citing, Ex. 32, at 2; Tr. at 151-52, 234.

[264] Ex. 23; Tr. at 150, 233.

Moreover, Staff noted that, should the Class 2 study conclude that Staff's Rail Option is reasonable, no additional studies would be required, thus saving time and money in the long run.[265] On the other hand, if a Class 5 study determines Staff's Rail Option is feasible, additional studies would be required, costing both time and money.[266]

Next, Staff contended that "[a] Class 2 study would compare an alternative not previously considered to the Company's current project plan ... and either result in a lower overall project budget or confirm that the Company has identified the least cost option for remediating the legacy CCR at Bremo and Possum Point before incurring additional major costs."[267]

In response to the Company's concerns that a Class 2 study would not be complete in time for the Company's 2022 Rider CCR filing, Staff pointed out that there is no requirement that the Company file its Rider 2022 filing in late February/early March as it did in the instant case.[268] In addition, Staff pointed out that the 2022 Rider CCR filing could include preliminary results of the Class 2 study and the final study could be filed upon completion.[269]

Regarding the Company's concerns that a Class 2 study would delay the Projects, Staff pointed out that there is room in the Bremo and Possum Point Project timelines to accommodate a six- to nine-month delay.[270] The Company anticipates the Bremo Project to take approximately 11-12 years and the Possum Point Project to take less time than that, both timeframes are well within the 15-year time limit set by SB 1355.[271]

Although the Company stated concerns that DEQ would pause the Company's currently pending Part A permit application upon notification by the Company that it is exploring other options, Mr. Stites conceded that there is no regulation requiring DEQ to halt its evaluation.[272] Further, the Company did not provide evidence that DEQ could not perform its assessment of the Company's Part A permit application while the Class 2 study was being performed.

In response to the Company's concerns that delaying the Projects would cause issues with sequencing the Projects and stacking more costs toward the end of the regulatory schedule, Staff pointed out that the Company projects a significant decline in the annual revenue requirement for the CCR Projects beginning in 2029 and declining further through 2035.[273]

Staff also suggested that the Commission may want to consider a Class 3 study if it shares the Company's concerns about time and money involved in a Class 2 study. Staff noted

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[265] Staff's Post-Hearing Brief, at 14, citing Tr. at 152.
[266] Tr. at 151.
[267] Staff's Post-Hearing Brief, at 16, citing Tr. at 155.
[268] *See e.g.,* Staff's Post-Hearing Brief, at 18; Tr. at 216-17.
[269] Staff's Post-Hearing Brief, at 18.
[270] *Id.* at 19.
[271] Tr. at 65-66, 236.
[272] Tr. at 235.
[273] Staff's Post-Hearing Brief, at 19-20, citing Exs. 2 and 2C, Filing Schedule 46C, Statement 2, p. 2, Exs. 22 and 22ES, at 29-30.

that a Class 3 study would cost less and take less time than a Class 2 study but would be far more precise than a Class 5 study. Nonetheless, Staff maintained its position that a Class 2 study is the preferred option and noted that, if a Class 3 study concluded that Staff's Rail Option is feasible, further studies would be required.[274]

I find the depth and precision of the Class 2 study is the more appropriate tool to consider the feasibility of Staff's Rail Option. The Class 2 study would provide a more thorough analysis of the feasibility of Staff's Rail Option and would provide more precise cost estimates. Moreover, no additional studies would be required, if the Class 2 study determines Staff's Rail Option is feasible. Although it would require more time to complete, both the Bremo and Possum Point Projects are still very early in their development, and the record shows that, even with a six- to nine-month delay, there is still time in the regulatory schedule to complete the Projects on time. Further, should the study confirm that Staff's Rail Option is feasible, the Company could begin the rail project upon completion of the study.

Projects to Include in the Study

In addition to the study's scope, the Company took issue with Staff's recommendation to include Bremo in the study. The Company asserted that it has made recent progress with the Bremo Project but is not as far along with Project development at Possum Point.[275]

In response to the Company's alternative proposal to exclude Bremo from the study, Staff first noted the relatively small investment, $12.6 million, the Company has made in the Bremo Project thus far. Staff also highlighted the significant projected costs, $529.9 million, involved in constructing the Bremo Landfill. Further, Staff pointed out that the Company does not expect to commence construction of the Bremo Landfill before the second quarter of 2023.[276] Moreover, Staff stressed that the same infrastructure built at or near the Curley Hollow Landfill or VCHEC should accept material from both Possum Point and Bremo.[277] Staff asserted that, "[b]ased on the Company's current projected timelines and the applicability of Staff's Rail Option to both Bremo and Possum Point, it is appropriate to include Bremo in the study of Staff's Rail Option."[278] Further, Staff contended that "there is sufficient time to complete a Class 2 study well before construction on the Bremo Landfill would commence, which would provide the necessary information to insure the least-cost option has been identified before the Company incurs additional significant costs."[279]

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[274] Staff's Post-Hearing Brief, at 16.
[275] *See e.g.,* Ex. 32, at 3-4; Tr. at 221-22. The Company anticipates filing permitting applications for Possum Point before the end of 2021 and contended that undertaking a Class 2 study would interfere with the permitting and Project sequencing process at Possum Point. The Company indicated that conducting a Class 5 study, however, could be performed without materially impacting the Possum Point Project schedule. *See* Company's Post-Hearing Brief at 17-18, citing Tr. at 221-22.
[276] Tr. at 218.
[277] Tr. at 202-03.
[278] Staff's Post-Hearing Brief, at 11.
[279] *Id.* at 11-12; Tr. at 155.

Ratepayers have already been paying for the Curley Hollow Landfill. The record shows there is likely ample capacity available there to support the CCR material from Bremo and Possum Point.[280] So far, there has been minimal investment (relative to overall budget) in both the Bremo and Possum Point projects.[281] If the study reveals that construction of a spur is feasible from the rail line to VCHEC or the Curley Hollow Landfill, ratepayers would realize a greater benefit from the rail spur investment as it would be utilized to transport CCR material from Bremo and Possum Point, rather than Possum Point alone.[282] Accordingly, I find the study should include Bremo.

FINDINGS AND RECOMMENDATIONS

Based on the Code and the record of this case, I find that:

(1) The Rider CCR revenue requirement of $216.146 million for the Rate Year is reasonable and should be approved;

(2) The Company's proposed 12-month amortization period for deferred costs is reasonable;

(3) The modified reporting requirements related to certain operational and financial milestones of the CCR Projects are reasonable and should be included with the Company's Rider CCR Annual Update filings;

(4) If the Company determines that lower cost options related to beneficiation solutions are technically feasible and can be implemented subject to statutory requirements and executed Company contracts, the Company should reflect the associated savings in reduced project estimates;

(5) The Company should include with its Rider CCR Annual Update filings the technological options it considered for each workstream for any significant contracts it awards, including the respective feasibility and costs analyses;

(6) The Company's proposed Factor 3 Non-bypassable allocation methodology and its uniform charge per kWh are reasonable and equitable, and should be approved; and

(7) Staff's Rail Option is reasonable, and the Company should be required to perform the Class 2 study that includes both Bremo and Possum Point.

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[280] Ex. 27C.

[281] Exs. 3 and 3ES, at 8, 16.

[282] As Ms. Kuleshova testified, "this infrastructure at VCHEC or Curley Hollow [L]andfill should accept material from both Possum Point and Bremo, that will be the same infrastructure. So different departure, same arrival...." Tr. at 202-03.

COMMENTS

The parties are advised that, pursuant to Commission Rule 5 VAC 5-20-120 C of the Commission's Rules of Practice and Procedure and § 12.1-31 of the Code, any comments to this Report must be filed on or before September 24, 2021. In accordance with the directives of the Commission's *COVID-19 Electronic Service Order*[283] the parties are encouraged to file electronically. If not filed electronically, an original and fifteen (15) copies must be submitted in writing to the Clerk of the Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218. Any party filing such comments shall attach a certificate to the foot of such document certifying that copies have been served by electronic mail to all counsel of record and any such party not represented by counsel.

Respectfully submitted,

Mary Beth Adams
Hearing Examiner

The Clerk of the Commission is requested to send a copy of this Report to all persons on the official Service List in this matter. The Service List is available from the Clerk of the Commission, c/o Document Control Center, 1300 East Main Street, First Floor, Tyler Building, Richmond, VA 23219.

[283] *Commonwealth of Virginia, ex rel State Corporation Commission, Ex Parte: Electronic service among parties during COVID-19 emergency*, Case No. CLK-2020-00007, Doc. Con. Cen. No. 200410009, Order Requiring Electronic Service (April 1, 2020) ("*COVID-19 Electronic Service Order*").